

part 5

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BROWN

COMPANY WITNESS DIRECT TESTIMONY SUMMARY

Witness: Dr. Richard E. Brown

Title: Principal Engineer and Practice Director, Exponent, Inc.

Summary:

Company Witness Brown provides testimony in support of the Company's Application for Virginia State Corporation Commission ("Commission") approval to revise the underground distribution rate adjustment clause to update Rider U for phase one ("Phase One") of the Strategic Underground Program ("SUP") and to recover the costs associated with phase two ("Phase Two") of the SUP through Rider U. Dr. Brown is an independent third-party consultant with Exponent, Inc., who provides an initial assessment of the performance of Phase One, as well as a summary of his cost-benefit analysis of Phase Two of the SUP as part of the Company's Application.

- Dr. Brown examined the performance of Phase One during the June 16, 2016 storm ("Father's Day Storm"). For the Father's Day Storm alone, the number of avoided outage events resulted in an outage event reduction (measured by work request reductions) of 3.15%, in comparison to a predicted reduction of or 4.21%.
- Dr. Brown estimated total economic benefits of \$5,478,251, consisting of Gross Domestic Product loss avoidance, customer hours of interruptions, and reduced food spoilage. The total annualized cost of Phase One is \$10,680,394. Thus, the Father's Day Storm resulted in more than 50% of the annualized total cost of Phase One. The Company has collected data concerning Phase One's performance during Hurricane Matthew, although analysis is not complete.
- For Phase Two, Dr. Brown's cost-benefit analysis evaluated the overhead-to-underground conversion of 244 miles of the most outage-prone tap lines in the Company's service territory. Dr. Brown employed the same cost-benefit analysis model employed in the Company's application for cost recovery for Phase One of the SUP.
- Dr. Brown's cost-benefit analysis concludes that the economic benefits to customers from Phase One outweigh its costs by a factor of 1.65:1. The annualized cost of 244 miles of undergrounding over the life of the facilities is \$8,394,790, while the total economic benefit to customers from Phase One is \$13,855,155 annualized over that same period.
- Dr. Brown's cost-benefit analysis is purposefully conservative and customers will receive additional benefits from Phase Two that are not part of his review.

**TESTIMONY
OF
RICHARD E. BROWN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2016-00136**

1 **Q. Please state your name, position, and business address.**

2 A. My name is Dr. Richard E. Brown, and I am Principal Engineer and Practice
3 Director for Exponent, Inc. My business address is 149 Commonwealth Drive,
4 Menlo Park, California 94025.

5 **Q. What is the purpose of your testimony in this proceeding?**

6 A. I am testifying in support of Virginia Electric and Power Company's ("Dominion
7 Virginia Power" or the "Company") annual update filing to the Rider U
8 underground distribution rate adjustment clause ("RAC" or "rider") for phase one
9 ("Phase One") of the Company's Strategic Underground Program ("SUP" or
10 "Program"). In addition, I am testifying in support of the Company's request for
11 approval by the State Corporation Commission of Virginia ("Commission") for
12 recovery of costs associated with phase two ("Phase Two") of the SUP through
13 Rider U pursuant to House Bill 848, Chapter 212 of the 2014 Virginia Acts of
14 Assembly ("Chapter 212") amending §§ 56-576 and 56-585.1 of the Code of
15 Virginia ("Va. Code" or "Code"). Under Chapter 212, a utility may petition the
16 Commission for approval of a rider for recovery of the costs of new underground
17 distribution facilities.

I will discuss the benefits of completed Phase One of the SUP. In particular, I examine the performance of Dominion Virginia Power related to the June 16, 2016 storm (the "Father's Day Storm"), which impacted an area where approximately 3% of overhead tap lines were converted to underground in Phase One. I also perform a prospective cost-to-benefit assessment of Phase Two of the SUP in a manner similar to what was performed in my report ("Report") for Phase One filed with the Company's Application in Case No. PUE-2015-00114, which is attached as Schedule 1.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. ___, REB, consisting of Schedule 1 (my Report), which was prepared during the Phase One filing under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Father's Day Storm Assessment

Q. Did the Father's Day Storm provide any indication of Phase One benefits?

A. Yes. Dominion Virginia Power experienced severe weather on June 16, 2016 that caused a four-day storm restoration effort. This storm resulted in more than 3,900 damage locations and in interruptions to almost 285,000 customers. Statistics for the Father's Day Storm are:

Father's Day Storm

Duration:	96	hours
Events:	3,904	events
Device Outage Events:	1,428	device outage events
Customers Affected:	284,269	customers
% of Customers Affected:	11.70	%
Customer Interruptions:	5,940,214	hours

Specific failure data was collected for the region associated with “Office 01 (Richmond)” and “Office 06 (East Richmond).” This region had a total of 62.29 miles (21.54 miles in Richmond and 40.75 miles in East Richmond) converted to underground in Phase One, and an additional 498.06 unconverted candidate miles (203.8 miles and 294.3 miles, respectively) identified in the total SUP. The percentage of completed SUP conversions for this region relative to the total number of overhead tap lines is 2.94%.¹

There were a total of 150 device outage events that occurred on the unconverted miles in Richmond and 83 device outage events on unconverted miles in East Richmond. If the converted miles had not been converted, it is estimated that there would have been 27.35 additional device outage events.²

The total number of device outage events in these two offices was 842. If no conversion had occurred, the estimated total number of device outage events would have been $842 + 27.35 = 869.35$. This corresponds to an estimated work request reduction percentage of $27.35 \div 869.35 = 3.15\%$.

The actual results of this storm can be compared to the predicted results of the storm according to the models developed in my Report. The primary feature of a storm in my Report is duration, which was 96 hours for the Father’s Day Storm.

¹ Examining the impact of undergrounding based on regions is imprecise since storms do not typically conform to the precise geography of regions. If parts of a region are not impacted fully or at all, benefit-to-cost ratios calculated for the region will appear artificially low. More precise results can be achieved by identifying smaller geographic areas impacted by a storm and aggregating these together as an analysis area. It is my understanding that Dominion Virginia Power is exploring this approach and my analysis described herein will be updated at such time that the predicted and actual results are reflective of the true storm footprint.

² $150 \times 21.54 + 203.8 + 83 \times 40.75 \div 294.3 = 27.35$.

Actual versus predicted values for this storm, based on a 96-hour total duration, are as follows:

Table 1. Actual vs. Predicted Values for Father's Day Storm

	Actual	Predicted
% Customers	11.14%	13.6% ³
Restoration Factor	0.2177	0.1025 ⁴
Customer Interruption Hours	5,940,214	3,246,828 ⁵

Table 1 shows that the Father's Day Storm was more severe than a typical 96-hour storm experienced by Dominion Virginia Power in the past. Slightly fewer customers experienced interruptions (11.14% vs. 13.6%), but almost twice the number of customer interruption hours occurred. Variability in the actual versus predicted values resulting from an individual storm's damage can be influenced by several factors. For example, heavy impact to substation and main feeder facilities can increase the number of customers impacted by a storm; a high concentration of damage to hard-to-access overhead facilities can increase the number of customer interruption hours. Thus, each storm is unique and presents its own challenges to restoration efforts. The Father's Day Storm caused damage to both main feeders and hard-to-access tap lines, but it also created significant barriers to typical traffic routes due to the storm's damage to non-utility facilities. In addition, a high level of fallen trees across roadways blocked repair access points and likely extended some outages. Surrounding areas were not as severely impacted by the Father's Day Storm, which enabled a faster convergence of repair resources and helped mitigate some of the early impediments to repair efforts.

³ See formula in Figure 6-2 of my Report ($0.000005 \times 96^2 + 0.001 \times 96 - 0.0063 = 13.6\%$).

⁴ See formula in Figure 6-3 of my Report ($0.00007 \times 96 + 0.0958 = 0.1025$).

⁵ $2,429,650 \times 13.6\% \times 0.1025 = 3,246,828$ hours.

Recall that my Report groups storms into categories A through G, with category A corresponding to the shortest storms and category G corresponding to the longest storms. The threshold between categories D and E is 96 hours, which is the duration of the Father's Day Storm. Therefore, the Father's Day Storm will be examined as a "D/E Storm." This is done by averaging predicted results from a D Storm with the predicted results from an E Storm.

Table 7-2 of my Report shows the expected work request reduction and crew-hour reduction for each storm category assuming 2% of overhead facilities in the identified overall SUP program have been converted (i.e., 400 miles out of 20,000 miles of overhead tap exposure). The average for a category D and E storm, assuming 2% conversion, is a 2.87% work request reduction and a 3.47% crew-hour reduction. However, the amount of conversion in this area was 2.94%, not 2%, therefore, expected benefits will be higher than a typical D/E storm.

Factoring the actual amount of conversion results in the following:⁶

Table 2. Actual vs. Predicted Benefits for Father's Day Storm

	Actual	Predicted
Work request reduction	3.15%	4.21%
Crew-hour reduction	3.81%	5.10%

For the Father's Day Storm, avoided device outage events are approaching what the model in my Report predicted: an actual work request reduction of 3.15% compared to a predicted reduction of 4.21%. Recall that the primary goal of the SUP is to avoid outage events in order to reduce storm restoration times. In this sense, Phase One of the SUP approached the performance expected for the

⁶ Crew-hours are assumed to be proportional to work requests.

Father's Day Storm. Crew-hour reduction is assumed to be proportional to the reduction in work requests, so the actual value would be $3.15\%/4.21\% \times 5.10\% = 3.81\%$.

Q. Can the economic benefits for the Father's Day Storm be estimated?

A. Yes. The largest component of economic benefits in the cost-benefit model is Gross Domestic Product ("GDP") loss avoidance, which based on a reduction in total length of restoration ("TLR"). This storm had an actual TLR of 96 hours, and a crew-hour reduction of 3.81%. Therefore, the TLR without any conversion would have been $96 \times 1.0381 = 99.66$ hours, corresponding to a TLR reduction of 3.66 hours.

Recall from my Report that GDP for Dominion Virginia Power's service territory is \$35,457,991 per hour. Recall also that the GDP factor used in my Report is 0.25, meaning that four hours of TLR reduction results in one hour of GDP loss avoidance. The Father's Day Storm interrupted 11.14% of customers. Therefore, GDP loss avoidance for the Father's Day Storm is $\$35,457,991 \times 3.66 \times 0.1114 \times 0.25 = \$3,614,268$.

There are also benefits corresponding to fewer customer hours of interruptions ("CHI"). Recall that the total CHI for the storm was 5,940,214 hours and the crew-hour reduction was 3.81%. This corresponds to a CHI reduction of 234,945 hours.⁷ Recall from my Report that the customer value for an avoided interruption hour is \$2.037. Therefore, the CHI benefit to customers for the

⁷ $3.81\% \times 5,940,214 \times 1.0381 = 234,945$.

Father's Day Storm is $\$2.037 \times 234,945 = \$478,583$.

The number of customers avoiding an outage is assumed to be proportional to work request reductions. In this case, work request reductions were 3.15%, corresponding to 9,236 customers avoiding an interruption.⁸ Since this storm was long enough to cause food spoilage, each of these customers is assumed to have avoided \$150 in food spoilage, for a total food spoilage benefit of $\$150 \times 9,236 = \$1,385,400$.⁹

The total economic benefit of Phase One for the Father's Day Storm is the sum of GDP loss avoidance, CHI reduction, and reduced food spoilage. A summary of benefits is:

Table 3. Summary of Father's Day Storm Benefits

Category	Benefit
Duration Saved (hours)	3.66
Customers avoiding device outage events	9,236
GDP Loss Avoidance (\$)	3,614,268
CHI Benefit (\$)	478,583
Avoided Food Spoilage (\$)	1,385,400
Total Economic Benefit (\$)	5,478,251

Recall from my Report that the total annualized cost of Phase One is \$10,680,394 per year. Therefore, the benefits corresponding to a storm like the Father's Day Storm equate to more than 50% of the annualized total cost Phase One.

My Report categorized storms into categories according to severity, and

⁸ $3.15\% \times 284,269 \times 1.0315 = 9,236$.

⁹ My Report assumes that each customer that avoids an interruption for storms greater than 2.4 days will avoid \$150 in food spoilage. This value is derived from the typical homeowner's insurance adder for food spoilage that covers \$500 in food spoilage.

calculated the frequency of each type of storm based on the Company's 17 years of historical storm data. This storm information is shown in Table 6-2 of my Report, and is reproduced as Table 4 here:

Table 4. Summary of Father's Day Storm Benefits

Storm	Duration (hrs)	Freq. (/yr)	Customers		Restoration Factor	Cust-Hours Interrupted
			%	#		
A	20.0	11.71	1.57%	37,229	9.72%	847,429
B	32.8	4.72	3.19%	75,694	9.81%	1,151,278
C	58.7	1.63	6.96%	165,155	9.99%	1,577,355
D	78.1	0.96	10.24%	242,708	10.13%	1,852,442
E	120.5	0.44	18.68%	442,938	10.42%	2,426,601
F	182.0	0.20	34.13%	809,314	10.85%	3,276,075
G	337.0	0.066	89.85%	2,130,493	11.94%	5,681,856
Total customer hours of interruption (per year)						16,813,036

Recall that the Father's Day Storm is a D/E storm. According to Table 4, a Category D storm occurs about once per year and a Category E storm occurs about every other year. Therefore, a D/E storm like the Father's Day Storm can be expected to occur about two out of every three years. In those years, the benefits of Phase One will amount to about half of the annualized costs of Phase One without even considering the benefits associated with other storms that occur throughout the year.

Hurricane Mathew Assessment

Q. Can an analysis similar to the one performed for the Father's Day Storm be performed for Hurricane Mathew?

A. At the time of this filing, the collected data has not been fully compiled to do this. This can certainly be performed once the collected data is fully compiled. Furthermore, Dominion Virginia Power has collected data on outage repair times, which can be used to verify and refine some of the assumptions in my Report.

1 **Q. To which assumptions in your Report are you referring?**

2 A. Table 7-1 in my Report lists the average number of crew hours required to address
3 various outage scenarios. Because Dominion Virginia Power did not have data
4 associated with this topic, the values were obtained through interviews with
5 Dominion Virginia Power crew managers. Dominion Virginia Power has now
6 collected field data to which Table 7-1 can be compared.

7 **Q. What does the new collected field data show?**

8 A. Field data was collected for various overhead outage categories, including the
9 time required for Dominion Virginia Power crews to clear vegetation. At this
10 point, only information on tap line repairs have been collected (i.e., no main
11 feeder data). Results are:

12 **Table 5. Crew Hours Required to Repair Outages**

Overhead Line Category	Number of Observations	Average Man Hours for Restoration
Back yard tap lines which require pole replacement	6	54
Back yard tap lines which require primary voltage wire to be re-strung	4	17
Back yard tap lines which require primary and secondary / service voltage wire to be re-strung	8	93
Front yard tap lines which require pole replacement	4	69
Front yard tap lines which require primary voltage wire to be re-strung	4	11
Front yard tap lines which require primary and secondary / service voltage wire to be re-strung	6	28
Totals	32	51 (weighted average)

13 Table 5 shows that the weighted average number of hours for crews to repair a tap
14 line outage is 51, including vegetation removal time. Without vegetation removal

time, this would be reduced to 46 hours. Both of these values are higher than the Table 7-1 value of 34.9 hours for tap line repairs.

My Report uses the relative values of main feeder repair time to tap line repair time to calculate the benefits of underground conversion. This is important for two reasons. The mere fact that actual crew hours are higher than previously assumed does not necessarily result in benefits that are higher or lower. Second, there is currently not enough field data to refine this aspect of the analysis. However, Dominion Virginia Power has made a good first step in gathering this information.

Phase Two Benefit-To-Cost

Q. Can a benefit-to-cost assessment be performed for Phase Two of the SUP in a manner similar to Phase One of the SUP?

A. Yes. An analysis of this type does not require a comprehensive “bottom-up” analysis similar to the Phase One analysis. Rather, Phase One results can be adjusted based on differences between Phase One and Phase Two.

This first important difference is scale. Phase One converted 400 miles of line whereas Phase Two is designed to convert 244 miles of line.

This second important difference is conversion cost per mile. The Phase One analysis assumed \$350,000 average cost per mile, whereas the Phase Two analysis will assume \$450,000 average cost per mile. The increase in cost per mile is largely due to Phase One focusing on the “easy” projects, such as a higher percentage of shorter lines with fewer associated customers. Since relatively

1 simple projects were largely completed in Phase One, more complicated projects
2 are being performed in Phase Two.

3 In terms of benefit, the Phase One projects were assumed to have benefits that are
4 representative of the overall SUP. Specifically, Phase One projects represent 10%
5 of the overall SUP program (i.e., 400 miles out of 4000 miles), and therefore
6 represent 10% of total SUP benefits. Phase Two projects are also assumed to
7 have benefits that are representative of the overall SUP. Since 244 miles is 6.1%
8 of the total SUP program, Phase Two benefits are assumed to be 6.1% of total
9 SUP benefits. This corresponds to 61.1% of the Phase One benefits ($244 \div 400 =$
10 61.1%).

11 **Q. What is the annualized cost of Phase Two?**

12 A. The annualized cost of Phase Two is calculated using the same assumptions that
13 my Report uses for Phase One. The total cost of Phase One was \$140,000,000 as
14 compared to a total cost of Phase Two of \$110,000,000, or 78.6% of the Phase
15 One cost. Since the annualized cost of Phase One is \$10,680,394, the annualized
16 cost of Phase Two is \$8,394,790.

17 **Q. What is the benefit-to-cost ratio of Phase Two?**

18 A. The benefit to cost assessment can be calculated by starting with the Phase One
19 results (Table A-1 in my Report), adjusting the cost by the above factor of 78.6%,
20 and adjusting the benefits by the above factor of 61.1%. The results are shown
21 below.

Table 6. Phase Two Benefit-to-Cost Assessment

Benefit-to-Cost Assessment (\$/yr)	
Costs	
Annualized cost of 244 miles	8,394,790
Benefits	
Reduced interruption hours	626,241
Reduced food spoilage	2,472,932
GDP loss avoidance	10,755,982
Total	13,855,155
Benefits / Costs	1.65

As can be seen, the benefit-to-cost ratio for Phase Two is lower when compared to Phase One (1.65 compared to 2.12), due to the higher cost per mile of Phase Two projects. Still, the benefit-to-cost ratio is significantly higher than one, indicating positive value for Dominion Virginia Power customers.

Q. Is the benefit-to-cost ratio of Phase Two conservative?

A. Yes. The benefit-to-cost ratio shown in Table 6 is conservative for all of the same reasons the Phase One benefit-to-cost ratio is conservative. Examples of conservative assumptions include no residual value of installed facilities after full depreciation and most storms truncated at midnight on their last day. Examples of benefits not considered include: improved reliability during non-storm conditions; increased property value due to improved aesthetics; reduced hotel/restaurant costs; enhanced public safety; and eventual lower utility operations and maintenance expenses.

It should be noted that the expected benefits of Phase Two are based on the storm frequency values shown in Table 4. These are based on storm data from 1997 through 2015. Storm activity in 2016 has been much more severe than the 1997-

2015 average, due to the Father's Day Storm and Hurricane Matthew. If the values in Table 4 were updated to reflect 2016, calculated benefits would be higher. Assuming the economic storm impact of 2016 is about twice that of the 1997-2015 average, calculated benefits would be about 6% higher and the benefit-to-cost would increase from 1.65 to about 1.75.

Since 2016 is not yet over, it is inappropriate to include 2016 in the benefit-to-cost analysis at this time. However, as calendar years are completed, it is appropriate to update the values of Table 4 to include as much historical weather data as possible, regardless of whether additional years correspond to mild weather (tending to reduce the benefit-to-cost ratio) or severe weather (tending to increase the benefit-to-cost ratio).

Conclusions

Q. Do you have any final comments?

A. Yes. Nobody wishes for major weather events to result in extensive customer interruptions. This said, the Father's Day Storm allowed Dominion Virginia Power to determine whether the spending on Phase One of its SUP delivered the expected benefits. For this storm, benefits were approaching the level expected. In addition, the customer economic benefits for just the Father's Day Storm amounted to 50% of the annualized cost of Phase One.

Q. Does this conclude your testimony?

A. Yes.

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**DIRECT TESTIMONY
OF
RICHARD E. BROWN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2015-00114**

1 Q. Please state your name, business address, and position of employment.

2 A. My name is Dr. Richard E. Brown, and my business address is Exponent, Inc.,
3 149 Commonwealth Drive, Menlo Park, California 94025. I am Principal
4 Engineer and Practice Director for Exponent, Inc. A statement concerning my
5 background and qualifications is Appendix A to my Schedule 1.

6 Q. Please describe your educational and professional background.

7 A. I received my Bachelor of Science in Electrical Engineering, Master of Science in
8 Electrical Engineering, and Ph.D. in Electrical Engineering from the University of
9 Washington in Seattle. I also received my Master of Business Administration
10 from the University of North Carolina at Chapel Hill. I am a registered
11 professional engineer in the State of North Carolina and a Fellow of the Institute
12 of Electrical and Electronics Engineers.

13 During my consulting career, I have helped numerous utilities develop cost-
14 justified reliability improvement plans. I have participated as an expert on the
15 subject of electric power distribution reliability assessment, reliability
16 improvement, major event assessment, major event hardening, and benefit-to-cost
17 assessment. I am the author of over ninety peer-reviewed technical papers and
18 two books. I have also provided expert witness testimony to regulatory

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1 commissions in the states of California, Florida, Maryland, Massachusetts, and
2 Texas.

3 **Q. What is your current title and what are your duties and responsibilities in**
4 **your current position?**

5 A. I am Principal Engineer and Practice Director for Exponent, Inc., an engineering
6 and scientific consulting company. In that capacity, I provide companies with
7 consulting expertise in infrastructure asset management, power system reliability,
8 major event performance, system hardening, reliability improvement, power
9 delivery system planning, smart grid, system automation, distributed energy
10 resources, risk assessment, and economic analysis.

11 **Q. Please describe the reason for your testimony in this case.**

12 A. I am presenting the results of my study, which evaluated the benefit-to-cost
13 comparison of 400 miles of overhead-to-underground conversion of tap lines in
14 the Virginia Electric and Power Company ("Dominion Virginia Power" or the
15 "Company") Virginia service territory. This study was performed in conjunction
16 with Dominion Virginia Power's application for approval of the first phase
17 ("Phase One" or the "Phase One SUP") of a Strategic Undergrounding Program
18 ("SUP"). The study is attached as Company Exhibit No. ___, REB, consisting of
19 Schedule 1, which was prepared under my supervision and is correct to the best of
20 my knowledge and belief.

21 **Q. What conclusions did you reach concerning the benefit-to-cost assessment of**
22 **Phase One?**

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1 A. I concluded that the benefits of the Phase One SUP outweigh its cost, meaning
2 that people living within the Dominion Virginia Power service territory are
3 economically better off with the implementation of Phase One than without it.
4 Specifically, I determined that the annualized cost of the 400 miles of
5 undergrounding over the life of the facilities is \$10,680,394, while the total
6 economic benefit to customers from Phase One is \$22,676,195 annualized over
7 that same period. As explained in my report, I also believe the report is
8 purposefully conservative and there will be additional benefits that will accrue to
9 customers that are not part of my benefit analysis.

10 In summary, a conservative assessment of cost and a conservative assessment of
11 benefits show that the economic benefits of the overhead-to-underground
12 conversion of 400 miles of overhead tap lines are significantly higher—in fact
13 more than two times higher—than the costs of this conversion.

14 Q. Does this conclude your direct testimony?

15 A. Yes, it does.

Company Exhibit No.
Witness: REB
Schedule 1
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Engineering Sciences

Exponent®

**Benefit-to-Cost Assessment of the
Dominion Virginia Power Strategic
Undergrounding Program**

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Exponent

**Benefit-to-Cost Assessment of the
Dominion Virginia Power Strategic
Undergrounding Program**

Prepared for:

Alan Bradshaw
Director of Electric Distribution Underground
Dominion Virginia Power
701 E. Cary Street,
Richmond, VA 23219
Alan.Bradshaw@dom.com

and

Charlotte P. McAfee
Senior Counsel, Law Department
Dominion Resources Services, Inc.
120 Tredegar Street, Riverside 2
Richmond, VA 23219-4306
Charlotte.P.McAfee@dom.com

Prepared by:

Richard E. Brown, Ph.D., P.E.
Exponent Inc.
149 Commonwealth Drive
Menlo Park, CA 94025
rbrown@exponent.com

November 24, 2015

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Limitations

At the request of Virginia Electric and Power Company ("Dominion Virginia Power" or "Company"), Exponent conducted an assessment of the facts related to the Company's Strategic Undergrounding Program and, in particular, its first phase ("Phase One"). The opinions and comments formulated during this assessment are based on observations and information available at the time of the assessment.

The findings presented herein are made to a reasonable degree of engineering certainty. If new data becomes available or there are perceived omissions or misstatements in this report regarding any aspect of those conditions, we ask that they be brought to our attention as soon as possible so that we have the opportunity to fully address them.

A benefit-to-cost assessment (BCA) has been performed for Phase One of the Dominion Virginia Power Strategic Undergrounding Program (SUP). This Phase One proposes to convert 400 miles of overhead tap lines in Virginia to underground, which is 2% of all tap line exposure and the minimum I recommended for this type of program. The primary goal of the SUP is to benefit Virginia customers by incurring less damage during major weather events and thereby reducing storm restoration time.

Dominion Virginia Power expects that Phase One of the program will take approximately three years to complete. The cost of undergrounding these 400 miles is approximately \$350,000 per mile, for a total cost of no more than \$140,000,000. This amount corresponds to an annualized cost of \$10,680,394 per year over thirty-nine years (the depreciation schedule for underground facilities). It is appropriate to compare this annualized cost to annual customer benefits for the purposes of a BCA.

A detailed storm and storm restoration model has been developed based on historical outage records of the Company's major weather events. This model is able to estimate the frequency of storms of various magnitudes, their restoration time, the number of customers affected, the number of customer interruption hours, and the number and types of damage locations. Using this model, the benefits of underground conversion have been quantified in terms of collective customer economic benefits and individual-level customer economic benefits from faster storm restoration leading to a faster return to normalcy. Collective customer economic benefits include increased GDP in the Company's Virginia service territory due to shorter storm restoration durations. Individual-level customer economic benefits include the value of reduced customer interruption hours and reduced food spoilage. Comparing the annualized costs to annual benefits results in the following BCA:

Table A-1. Benefit-to-Cost Assessment

Benefit-to-Cost Assessment (\$/yr)	
Costs	
Annualized cost of 400 miles	10,680,394
Benefits	
GDP loss avoidance	17,603,898
Reduced Interruption hours	1,024,945
Reduced food spoilage	4,047,352
Total	22,676,195
Benefits / Costs	2.12

This BCA is conservative due to both conservative assumptions and additional customer benefits that are not monetized for purposes of this analysis. Examples of conservative assumptions include no residual value of installed facilities after full depreciation, most storms truncated at midnight on their last day, no customer growth, and no GDP growth. Examples of benefits not quantified in this study include improved reliability during non-storm conditions; reduced hotel/restaurant costs; state economic development benefits resulting from implementation of the program; enhanced public safety; and lower operations and maintenance expense for the utility over time.

In summary, a conservative analysis shows that a Dominion Virginia Power program of converting 400 miles of tap lines from overhead to underground has a Virginia customer benefit-to-cost ratio of more than two to one.

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1. Introduction

Historically, electric utilities did not design electric distribution systems to be able to withstand major weather events such as hurricanes and tornados, or other significant weather events such as thunderstorms and wind storms. Utilities designed their systems to be safe during normal conditions, and were expected to perform an efficient restoration after a major weather event.

Over the last several decades, there has been an increasing trend for utilities to spend more money on distribution systems than is strictly required for safety reasons in order to provide higher levels of reliability to customers, who are increasingly impacted by power interruptions with each passing year. Most utilities are focusing this additional spending on areas that are intended to improve reliability during normal weather conditions, and state utility commissions across the country are nearly uniform in agreement that this reliability-based spending, if done in an appropriate way, is beneficial for customers and is worth the cost.

Many approaches to improving normal-weather reliability have minimal benefits during major weather events. Over the past decade, many state legislatures, utility commissions, and utilities have therefore asked the question, "Should we consider spending money on system improvements that will reduce infrastructure damage during major events?" Once complete, these improvements will result in fewer damage locations, faster restoration times, lower storm restoration costs, less customer inconvenience, and regional economic benefits.

One example is Florida, which was hit by three major hurricanes in 2004 and two major hurricanes in 2005. As a result, the Florida Public Service Commission (Florida Commission) required all utilities under its jurisdiction to file storm hardening plans to help reduce infrastructure damage during future major weather events. The Florida Commission also contracted out a comprehensive study on the costs and benefits of overhead-to-underground conversion in that state, since undergrounding is a straightforward method to harden distribution facilities in many situations.

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outage-prone tap lines will reduce about 10% of total tap line damage, corresponding to about a 5% reduction in total restoration effort for a wide range of storm scenarios.³

The Company currently has about 20,000 circuit miles of overhead distribution tap lines. Two percent of this corresponds to 400 miles, which is my minimum recommended amount, and is appropriate to consider as a stand-alone Phase One project.

Therefore, this report shall perform a benefit-to-cost analysis of 400 miles, corresponding to the Phase One of Dominion's planned overhead-to-underground conversion. The Company expects that it can accomplish this Phase One in three years by August 31, 2016.

The assessments made in this report are based on the knowledge, education, training, and industry experience of the author.

³ These are typical values based on the author's experience. Dominion-specific calculations are performed later in the report.

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2. Author Qualifications

Richard E. Brown is an internationally-recognized expert on electric power distribution reliability assessment, reliability improvement, major event assessment, major event hardening, and benefit-to-cost assessment. He is the author of over ninety peer-reviewed technical papers and the books *Electric Power Distribution Reliability* and *Business Essentials for Utility Engineers*. The first book covers the engineering aspects of cost-effective reliability improvement and storm hardening, and the second book covers benefit-to-cost assessment in detail. He received his BSEE, MSEE, and PhD degrees from the University of Washington in Seattle, and his MBA from the University of North Carolina at Chapel Hill. He is a registered professional engineer and a Fellow of the IEEE. Dr. Brown's CV is provided in Appendix A.

Dr. Brown has performed dozens of benefit-to-cost studies for utilities with regards to reliability excluding major storm events. These studies are not listed here⁴ so that this section can focus specifically on experience with system hardening and benefit-to-cost analysis as they relate specifically to major weather events. Below are projects performed by Dr. Brown that relate to these areas.

Cost-Benefit Analysis of the Deployment of Texas Utility Infrastructure Upgrades and Storm Hardening Programs. Prepared for the Texas Commission and filed under docket number 36375. The results of this report were presented to the commission in an open meeting on April 9, 2009. This report examines the impact of hurricanes and tropical storms to electric and telecom utilities in Texas. It examines the cost-effectiveness of potential hardening programs such as vegetation patrols, hazard tree programs, ground-based inspections, locating substations outside of floodplains, emergency backup generation in central offices, underground conversion, smart grid technologies, targeted hardening, and post-storm data collection. This report determines the costs for each program, the direct utility benefits, and societal economic benefits.

⁴ Available upon request.

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Florida Undergrounding Benefit-to-Cost Assessment. This project performed a three-phase project for a consortium representing all electric utilities in Florida (managed through the Public Utility Research Consortium of the University of Florida). Phase 1 performed a comprehensive literature review and assessment.⁵ Phase 2 performed four case studies of completed underground conversion projects.⁶ Phase 3 developed a hurricane simulation model capable of predicting the costs and benefits to all stakeholders for potential underground conversion projects, as well as comparing these costs and benefits to a hardened overhead system.⁷

Hurricane Hardening Roadmap, Florida Power & Light. This project developed a hurricane hardening roadmap for Florida Power & Light (FPL). This included the development of a "hardening toolkit," standards, specifications, criteria, application guidelines, and supporting tools. It also included a pilot study that demonstrated and refined these concepts, and provided a basis for a ten-year roadmap in terms of projected cost and effort. Last, this project developed a ten-year reliability roadmap that achieved all FPL's distribution hardening objectives for the least possible cost.

Baltimore Gas & Electric: System Hardening and Reliability Improvement. BGE was ordered by the Maryland Public Service Commission (Maryland Commission) to submit a report on short-term reliability enhancements and another report on longer-term system hardening initiatives. This project supported BGE in assessing their current reliability and storm hardening initiatives, performed a technology review, performed detailed cost-to-benefit analyses for various reliability improvement and storm hardening scenarios, assessed their storm damage modeling systems and processes, and prepared the Maryland Commission reports.

Pepco Reliability and Storm Performance Assessment. Prepared direct testimony, reply testimony, and surreply testimony. Submitted to the Maryland Public Service Commission

⁵ R. E. Brown, *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion*. Submitted to the Florida Public Service Commission per order PSC-06-0351-PAAEI, Feb. 2007.

⁶ R. E. Brown, *Undergrounding Assessment Phase 2 Final Report: Undergrounding Case Studies*. Submitted to the Florida Public Service Commission per order PSC-06-0351-PAAEI, Aug. 2007.

⁷ R. E. Brown, *Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modeling*. Submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI, May 2008.

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under Case No. 9240. This testimony performed a review of the reports generated to assess the reliability of Pepco's reliability and customer service during both normal and major event conditions.

Extreme Wind Hardening Benchmark Survey, BC Hydro. This project performed a survey of hardening initiatives of utilities in the Pacific Northwest following the severe wind storms of December 2006. This project also surveyed hardening initiatives in other parts of the country and around the world.

Distribution Hardening: Benchmark Survey and Best Practices. Prepared for the Public Utilities Commission of Texas and filed under docket number 36375. The results of this report were presented to the commission in an open meeting on July 30, 2009. An industry benchmark survey was performed to determine typical and best industry practices related to hardening distribution systems so that they experience less damage during major storms. The report identifies eighteen recommendations.

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3. Strategic Undergrounding Program Overview

The Company's distribution system consists of three-phase electric circuits typically referred to as "feeders." A feeder consists of a three-phase "main feeder," and "tap lines" that route power from the main feeder to a majority of customers. Most tap lines are single-phase.⁸ The Company's distribution system has a total of about 58,000 circuit miles, and about 20,000 of these circuit miles are overhead tap lines.

The Company's service territory is subject to a variety of major weather events including hurricanes, linear winds, and winter storms. In each case, most distribution system damage tends to be caused by trees falling into overhead facilities. An effective way to prevent this type of damage is to convert overhead facilities in heavily-treed areas to underground. However, many studies have shown that the complete conversion of all overhead distribution facilities to underground is cost-prohibitive.

Undergrounding three-phase main feeder lines is much more expensive than undergrounding single-phase tap lines. This is due to the need for larger cable, pad-mounted switch devices, and vault and concrete duct bank systems. In contrast, most single-phase tap lines can be installed using directional boring or simple trenching. By design, the Strategic Undergrounding Program targets single-phase tap lines for undergrounding to achieve greater reliability improvements at a relatively low cost.

Dominion Virginia Power has ranked all of its single-phase tap lines based on the number of outages experienced over the past ten years, normalized by length. This results in an "outage events per mile" metric that is indicative of the likelihood of future storm damage (very short tap lines are excluded from consideration). The Company has ranked all tap lines based on the number of outage events per mile, and has identified the highest ranked 4000 miles as

⁸ Three-phase main feeders typically consist of four wires (three phase wires and one neutral wire). Single phase tap lines typically consist of two wires (one phase wire and one neutral wire).

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candidates for eventual undergrounding. These 4000 miles consist of over 11,000 tap lines ranging from 0.1 miles to 2.5 miles in length.

As stated previously, an appropriate Phase One for an undergrounding program of this nature should underground at least 400 miles of tap lines in order to reliably and significantly reduce damage incurred during major weather events. The Company states that it can accomplish the 400 miles of undergrounding in Phase One within three years by August 31, 2016. The Company also states that the tap lines selected for the first 400 miles will represent a range of situations in order to better understand the full range of design and construction issues. As such, the tap lines that will be undergrounded in the first three years are expected to have per-mile benefits similar to the entire 4000 miles of the most outage prone tap lines.

Discussion on Alternatives

The Final Order expresses concern that "Dominion presented no evidence showing that it considered whether any possible alternatives to its proposed SUP could increase reliability at a lower, and reasonable, cost to ratepayers." In response, this report will address alternatives to a targeted SUP.

In terms of extreme weather hardening, there are five primary approaches that can be applied broadly across a distribution system. These approaches are:

Primary Hardening Categories

1. Strengthen the overhead main-feeders;
2. Underground the overhead main-feeders;
3. Strengthen the overhead tap lines;
4. Underground the overhead tap lines; and
5. More aggressive vegetation management.

System-wide undergrounding of overhead main feeders has been consistently shown to be extremely expensive due to the need for vault and concrete ductbank systems (these also result

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in higher inspection and maintenance costs). Therefore, a detailed analysis is not required to know that this approach is not cost-effective for broad application.⁹

In the case of Dominion, strengthening entire tap line runs also does not make sense since this would be more expensive than undergrounding, and result in reduced benefits during major weather events.

Most of the damages incurred by the Company during major weather events are due to trees falling into poles and wires. Most of these trees are growing outside of the Company right-of-way, making tree removal essentially impossible without widening the right-of-way. The Company already prunes branches above the "hinge point" so that any branch that splits at the trunk and swings down will not contact overhead conductors. Therefore, there is no significant hardening opportunity related to pruning standards.

And so, the remaining practicable hardening approaches are strengthening the overhead main-feeders and underground the overhead tap lines.

The Company has a mature reliability program that is focused on the reliability improvement of overhead main feeders. A lot of this work is focused on improving major storm reliability. For example:

- Main feeder rebuild projects are selected based on expected improvements to "all-in SAIDI," which includes interruptions during major weather events;
- Some "ground-to-sky" tree pruning has been done in areas of hardwood trees, where pruning to above the hinge point is less effective when compared to softwood trees;
- Highway crossings have a "double dead end" standard, to ensure that conductors do not fall onto the highway surface; and
- Tall steel poles have been used instead of standard-height wood to supply certain critical loads.

⁹ This report later show that the Company is able to convert tap-lines for about \$350,000 per mile, whereas the conversion of main trunk lines will typically exceed several million dollars per mile.

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Very few utilities have formal overhead distribution hardening programs, and Dominion Virginia Power is no different. However, many of the same projects that would be addressed in a formal overhead distribution hardening program are already being addressed by the Company's reliability program.

In summary, the Company is appropriately addressing distribution system hardening by focusing on overhead main feeders through its reliability program and by focusing on overhead-to-underground conversion of its tap lines. This answers the broad question. The narrow question is then, "is the Company's approach to the conversion of overhead-to-underground tap lines appropriate?" This question can be further broken down as follows:

1. Is the SUP tap line selection process appropriate?
2. Is the SUP size appropriate (*i.e.*, 400 miles for Phase One)?
3. Do the benefits of the SUP outweigh its costs?

Is the SUP selection process appropriate? The current selection process ranks overhead tap lines by outage frequency per mile experience over the last ten years. The use of ten years of data is sufficient to get statistically meaningful results on all but the shortest tap lines, which the Company excluded for this reason.¹⁰ In general, the goal of storm hardening is to reduce total restoration time. All things being equal, the Company's use of outage events per mile best achieves this goal. In the real world, not all things are equal. For example, some tap line undergrounding projects may be more expensive than others (*e.g.*, those in rocky areas), and some overhead tap lines may take more crew resources to repair after being damaged during a storm (*e.g.*, locations not accessible by a bucket truck). At this point the Company does not have sufficient data to use a more complicated approach that considers such factors, and will not until Phase One is completed. Therefore, the use of outage events per mile is appropriate, but the Company should continue to gather data that could potentially result in an improved selection process.

¹⁰ Tap lines shorter than 400 feet are excluded since, by pure chance, several outages would rank very short feeders very high, but without statistical significance.

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Is the SUP size appropriate? This report is focused on assessing the planned Phase One of the SUP. As noted, a hardening program needs to be of sufficient scale for it to reliably result in reduced damage during storms. Based on my experience, a minimum of 2% of tap line exposure needs to be converted to meet this criterion. The Company has about 20,000 miles of tap lines, of which 2% corresponds to 400 miles. Therefore, it is the author's opinion that a minimum of 400 miles of conversion is reasonable and appropriate, which corresponds to Phase One.

Do the benefits of Phase One outweigh its costs? The remainder of this report addresses this question in detail. Section 4 addresses costs, and the following sections address benefits and the benefit-to-cost assessment.

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4. Cost Assessment

In its initial filing, the Company used an estimated overhead-to-underground conversion cost of \$500,000 per mile for undergrounding all 4000 miles of the system's most-outage prone tap lines. That value was based on both a representative sample of completed projects plus an adder to account for expected differences in SUP projects over the course of entire undergrounding program. While the representative sample of completed projects in the Company's initial filing had an average cost of about \$400,000 per mile, the Company anticipated higher costs for the SUP program due to the extensive use of directional boring, more extensive customer communication/outreach, increased modification of customer services, additional surveying costs, and the identification of private utilities. Those expected higher costs, when added to the average cost of the representative sample of completed projects, resulted in the \$500,000 per mile estimate to complete the undergrounding of all identified tap lines in the Company's 2014 SUP filing.

In contrast, the 400 miles of Phase One are to be focused on tap lines that are generally less problematic from a construction perspective. For example, as outlined in Company Witness Bradshaw's testimony, the Company has initially focused on single tap line projects that do not have third-party attachments before moving into more complex subdivision projects. Due to this initial selection filter and based on actual costs incurred on recent conversion projects, the per-mile cost of the first 400 miles included in Phase One is estimated to cost \$350,000 per mile, or \$140 million in total.¹¹

For the purposes of a benefit-to-cost analysis, the benefits of a particular tap line conversion begin as soon as a particular project is complete, and continue throughout the useful life of the newly-undergrounded tap line. Therefore, annualized costs will be compared against annualized benefits when performing the benefit-to-cost analysis.

¹¹ Per unit costs for completed projects consist of the direct-assigned costs (mostly field labor and materials) and a allocated cost for engineering and design. Only engineering and design costs for the first 400 miles are included in the \$350,000 per mile value.

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The Company currently depreciates underground assets on a 39-year schedule; 39 years is therefore assumed to be the useful life of the installed assets.

When calculating the annualized cost of Phase One, the following assumptions are made:

- \$140 million is raised at the start of the project;
- The weighted average cost of capital (*discount rate, d*) is 7.1040%;
- The expected life of a newly-undergrounded lateral tap (*time, t*) is 39 years; and
- Interest is compounded annually.

With these assumptions, an annuity factor *A* can be calculated. This is the percentage of the initial amount that must be paid each year so that the initial amount is completely repaid over the life of the project (in this case 39 years). The annuity factor for Phase One is calculated as follows:

$$A = \frac{d}{1-(1+d)^{-t}} = \frac{0.07104}{1-1.07104^{-39}} = 0.07629$$

Based on this calculated annuity factor, the annualized cost that will completely pay for the initial three years of the SUP is calculated as follows:

$$\text{Annualized Cost} = \$140,000,000 \times 0.07629 = \$10,680,394$$

This annualized cost is conservative since the calculation assumes no residual value after 39 years. In fact, it will be much less expensive to replace cable at the end of 39 years when compared to the per-mile SUP cost in many of the converted tap line locations. This is because SUP cable is installed in conduit, and replacement therefore consists of simply pulling out the old cable and pulling in new cable. Customer communications requirements would be much less, no new easements would be required, trenching/boring is not necessary, and service conversions are not necessary. All of this residual value is not considered in this annualized cost calculation, which is therefore conservative.

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5. Storm Outage Data

The Company has been collecting outage data in its outage management system (OMS) since 1997. In addition to collecting information on individual outages, the OMS contains data on all "qualifying events" that meet the criteria for exclusion when calculating reliability indices such as SAIFI and SAIDI. These qualifying events are, in the vast majority of circumstances, associated with major weather events that would benefit from Dominion's undergrounding program.

When examining major weather events, it is important to remove all qualifying events from the data set that would not benefit from an undergrounding program so that benefits are not overstated. Therefore, the following categories of qualifying events were excluded when performing the analysis:

Excluded Qualifying Events

- Salt contamination events;
- Transmission events; and
- Substation events.

The remaining qualifying events are all related to severe weather and include categories such as ice/snow, hurricanes, tornadoes, wind, and thunderstorms.

For each qualifying event, the OMS system stores the start time, the end time, and the storm type. In addition, the following information has been collected since 2001: number of customers affected, number of protection devices affected, and the total number of outage events (multiple events can occur downstream of a protection device), and the total number of customer interruption hours.

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A summary of qualifying event data is:

Qualifying Event Data

- Start Time (since 1997)
- End Time (since 1997)
- Storm Type (since 1997)
- Number of Customers Affected (since 2001)
- Number of Protection Devices Affected (since 2001)
- Number of Outage Events (since 2001)
- Customer hours of interruption (since 2001)

It should be noted that a disproportional number of events of 24-hrs in length appear in the data set. This is because the IEEE major event criterion is based on a calendar day. If a major event extends a few hours past midnight, these hours are not likely to be considered part of the major event statistics. For this reason, the benefit-to-cost calculations are conservative (*i.e.*, under-represent actual benefits).

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6. Major Weather Event Modeling

Using the storm modeling data described in the previous section, a major weather event model has been developed. This was done by grouping qualifying events (less the excluded categories) into seven bins, labeled Bin A through Bin G, based on the length in hours of the qualifying event. Each bin is then characterized by the average length of events it contains, and the number of events it contains. This process resulted in the bin characteristics shown in Table 6-1.

Table 6-1. Bin Statistics of Qualifying Events

Bin	Bin Range (hours)		Count	Event Hours	
	Low	High		Total	Avg.
A	0	24	225	4500	20.0
B	24	48	142	4662	32.8
C	48	72	28	1644	58.7
D	72	96	11	859	78.1
E	96	144	7	843	120.5
F	144	216	3	546	182.0
G	216	466	2	674	337.0

A plot of average bin duration versus event frequency is shown in Figure 6-1. Event frequency, or the average number of the given type of weather events per year, is equal to the bin count divided by the number of years represented in the data set – in this case, 18.7 years (January of 1996 through mid-September 2015). The vertical axis is shown as a logarithmic scale since events with long durations are much less frequent than events with relatively short durations.

Figure 6-1 also shows a function that closely represents the underlying data. This function shows that event frequency decreases according to a negative power of event duration. Due to the very high R-squared value of the curve fit, the following function is used to model the expected event frequency (per year) as a function of event duration (hours):

$$\text{Frequency} = 2831.5 \times \text{Duration}^{-1.832}$$

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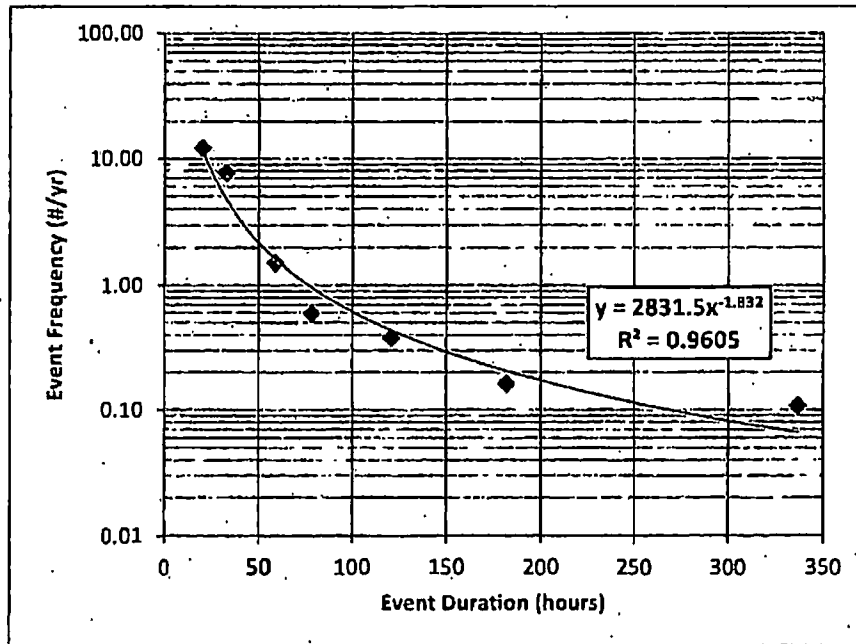


Figure 6-1. Plot of average bin duration versus bin frequency.

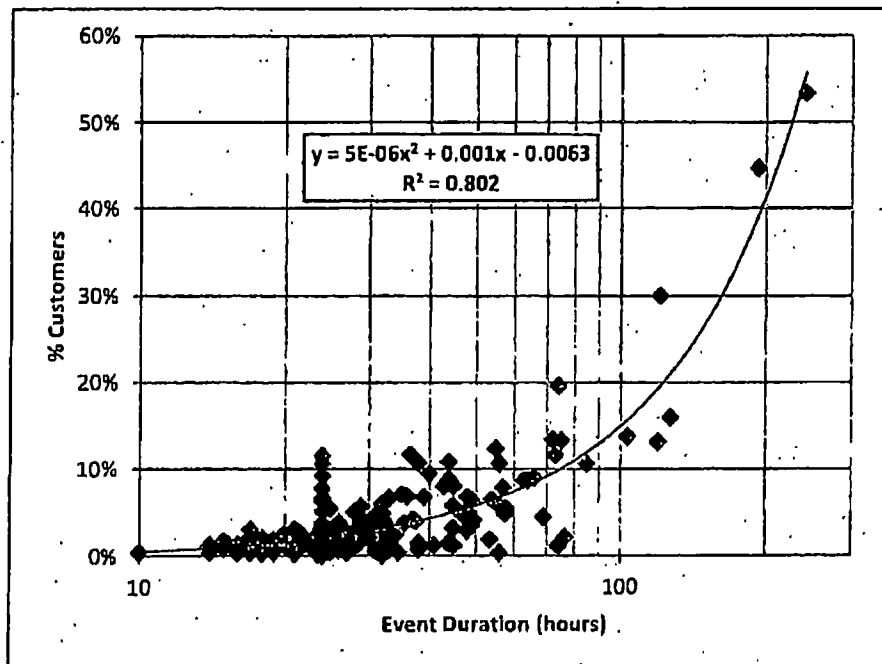


Figure 6-2. Plot of average percentage of customer interruptions versus event duration.

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In order to perform a benefit-to-cost analysis, it is also necessary to model the expected number of customers that will be affected by a major weather event of a particular duration (longer events tend to interrupt more customers). To do this, a scatterplot was generated using all relevant qualifying event data (January 2001 through mid-September 2015, less the excluded categories). This scatterplot is shown in Figure 6-2.¹² This figure also shows a function that closely represents the underlying data. This function shows that the percentage of customers interrupted increased according to second-order polynomial function of event duration. Due to the very high R-squared value of the curve fit, the following function is used to model the expected percentage of customers interrupted as a function of event duration (hours):

$$\% \text{ Customers} = 0.0005 \times \text{Duration}^2 + 0.01 \times \text{Duration} - 0.063$$

One of the factors that impacts customer costs during a major weather event is the total number of customer interruption hours. To examine this aspect, the concept of "restoration factor" is introduced. Consider a major weather event with a total duration, h in hours, and a total number of interrupted customers, c . If all interrupted customers are interrupted for the entire length of the event, the number of customer interruption hours is equal to $h \times c$. The outage management data has the actual number of customer hours of interruption for each event, CHI . The ratio of CHI to $(h \times c)$ is defined as the restoration factor.

$$\text{Restoration Factor} = CHI \div h \times c$$

A scatterplot of restoration factor versus event duration is shown in Figure 6-3.¹³ This scatterplot can be modeled by the following linear function:¹⁴

¹² The OMS data contains the number of customers interrupted for each qualifying event. The total number of Dominion Virginia Power customers at the date of each event was added and used to compute a percentage.

¹³ Recall from Section 5 that the IEEE major event criterion is based on a calendar day, which results in a disproportional number of events being 24 hours in duration. This can be seen in the figure.

¹⁴ The R-squared value for the linear regression is low due to the large number of events being 24 hours in duration but having widely varying restoration factors. This is not concerning since this part of the scatterplot is a result of truncating qualifying events at the end of a calendar day.

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$$\text{Restoration Factor} = 0.00007 \times \text{Duration} + 0.0958$$

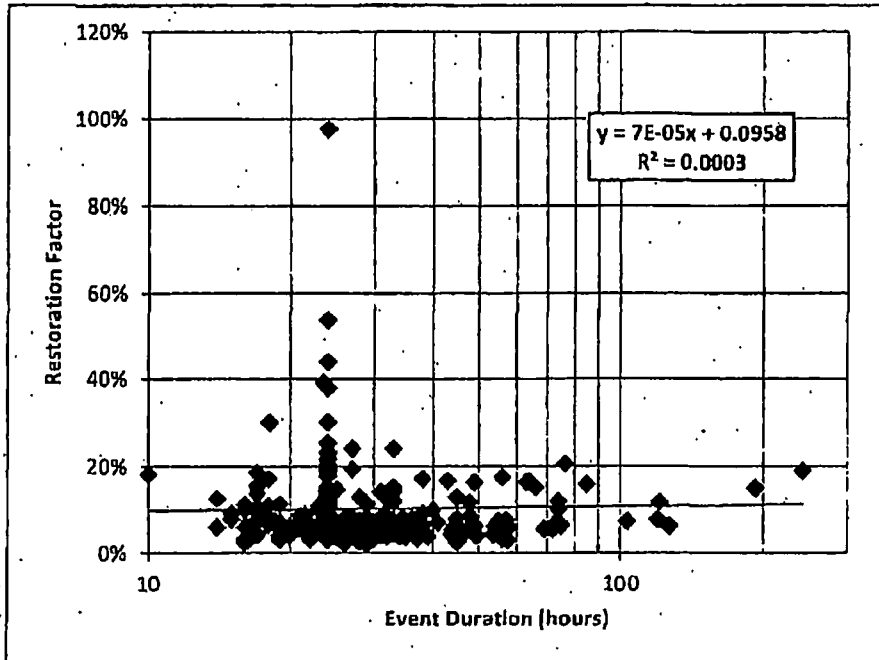


Figure 6-3. Restoration Factor versus Event Duration.

Using this formula for Restoration Factor, the expected number of customer hours of interruption associated with each bin can be calculated. This is equal to the product of the average duration of the bin, the frequency of the bin (according to the frequency model), the number of customers interrupted (according to the customers-versus-duration model), and the restoration factor (according to the Restoration Factor model).

Together, the above models allow for a major weather event model to be created that represents Dominion. This model consists of seven representative major weather events, labeled Storm A through Storm G, corresponding to Bins A through Bins G in Table 6-1. Each storm is characterized by a duration, a frequency, the number of customers experiencing an interruption per storm, a restoration factor, and the expected total number of customer hours of interruption

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attributable to this type of storm in a typical year.¹⁵ This information is shown in Table 6-2. It is important to note that this data is based on historical storm data. In some mild years, the number of storm events may be below the historic average; in other years, the number of extreme weather events may be above the historic average. But over time, we can expect weather event model to follow historic trends.

Table 6-2. Major Weather Event Restoration Model for Dominion Virginia Power

Storm	Duration (hrs)	Freq. (/yr)	Customers		Restoration Factor	Cust-Hours Interrupted
			%	#		
A	20.0	11.71	1.57%	37,229	9.72%	847,429
B	32.8	4.72	3.19%	75,694	9.81%	1,151,278
C	58.7	1.63	6.96%	165,155	9.99%	1,577,355
D	78.1	0.96	10.24%	242,708	10.13%	1,852,442
E	120.5	0.44	18.68%	442,938	10.42%	2,426,601
F	182.0	0.20	34.13%	809,314	10.85%	3,276,075
G	337.0	0.066	89.85%	2,130,493	11.94%	5,681,856
Total customer hours of interruption (per year)						16,813,036

Consider Storm A in Table 6-2, which corresponds to a 20-hour restoration event that occurs about once per month (frequency of 11.71 per year). A typical restoration of this duration will interrupt 1.57% of customers which corresponds to 37,229 Company customers in Virginia. Since the restoration factor is 9.72% for a 20-hour storm, interrupted customers will, on average, have interruption durations of 20 hours x 9.72% = 1.944 hours. The total expected number of annual customer interruption hours associated with this storm is therefore equal to 1.944 x 11.71 x 37,229, which corresponds to the last column in Table 6-2.¹⁶

Next consider Storm G in Table 6-2, which corresponds to a 337-hour restoration that occurs about once every fifteen years (frequency of 0.07 per year). A typical restoration of this duration will interrupt 89.85% of customers which corresponds to 2,130,493 Company customers in

¹⁵ Both the number of customers affected and the customer hours of interruption are based on the number of Virginia customers that will be affected by the rider, which is 2,371,240. Actual numbers will be higher due to non-Virginia customers and Virginia customers that would not be impacted by a rider.

¹⁶ The calculations in Table 2 are performed in a spreadsheet using numbers with higher precision, resulting in a slight difference when compared to the hand calculation.

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Virginia. Since the restoration factor is 11.94% for a 337-hour restoration, interrupted customers will, on average, have interruption durations of $337 \text{ hours} \times 11.94\% = 40.24 \text{ hours}$. The total expected number of annual customer interruption hours associated with this storm is therefore equal to $40.24 \times 0.066 \times 2,130,493$, which corresponds to the last column in Table 6-2.¹⁷

The total expected number of customer hours of interruptions per year due to major weather events is equal to the sum of the results for Storms A through G, which is equal to 16,813,036 hours per year. Again, as noted previously, mild years will be lower and years with extreme weather will be higher, but this is the average value over time.

¹⁷ See above footnote.

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Table 7-1. Typical Resource Requirements for Damage Locations

Event	Typical Crew Size	Typical Repair Time (hrs)	%	Avg. Crew Hours
Main Feeder Device Events				
Pole Down	6	6-8	30%	42
Wire Down, primary only	4	4-6	35%	20.0
Wire Down, primary + secondary	4	6-8	35%	28.0
Main Feeder Average			100%	29.4
Tap Line Device Events				
Pole Down, roadside	4	4-6	10%	20.0
Wire down, primary only, roadside	2	2-4	11%	6.0
Wire down, pri. + sec., roadside	2-4	4-6	11%	15.0
Pole Down, rear lot	8	10-12	20%	88.0
Wire down, primary only, rear lot	4-5	4-6	24%	22.5
Wire down, pri. + sec., rear lot	4-5	6-8	24%	31.5
Tap Line Average			100%	34.9
Non-Device Events (premise, transformer)				
	2	2-3	100%	5.0

The Company has calculated the number of total work requests that were issued during each qualifying storm (each work request corresponds to a damage location, and is referred to hereafter as simply an "event"). The Company has also calculated the number of device events that were issued during each qualifying storm. The difference in these two values is equal to the number of premise and service transformer events that occurred during the qualifying storm.

For each qualifying storm, the Company has additionally calculated the percentage of device events that correspond to tap lines that have been identified as the system's most outage-prone tap lines. This percentage has been multiplied by 0.10 since 400 miles corresponds to 10% of 4000 miles. The resulting percentage is equal to the expected percentage of device events that would be avoided for each type of storm. These percentages are shown in the "SUP Devices" column in Table 7-2.

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Table 7-2. Storm Restoration Reduction Model

Storm	Duration (hrs)	Events			Prem/Tx Factor	SUP Devices	WR Reduction	Crew-Hr Reduction
		Total	Device	Prem/Tx				
A	20.0	47,358	26,107	21,251	0.90	2.55%	2.44%	2.96%
B	32.8	50,820	28,141	22,679	0.90	2.77%	2.64%	3.21%
C	58.7	21,668	12,922	8,746	0.90	3.00%	2.88%	3.49%
D	78.1	10,791	5,660	5,131	0.90	2.64%	2.52%	3.05%
E	120.5	12,410	7,381	5,029	0.90	3.34%	3.21%	3.89%
F	182.0	11,440	5,292	6,148	0.90	2.87%	2.71%	3.28%
G	337.0	68,142	22,918	45,224	0.90	2.02%	1.88%	2.25%

After the conversion of Phase One is complete, fewer events will occur during a storm and fewer crew hours will be required to repair these events. To calculate these amounts, it is assumed that an undergrounded tap line completely avoids device events caused by wind, ice, and trees. It is also assumed that non-device events are reduced by 90%, since most customers will have their service drops converted from overhead to underground (this value is shown in the "Prem/Tx Factor" column in Table 7-2). Last, it is assumed that tap line device events have, on average, 20% higher crew-hour requirements to repair than main line device events, and that device events on average take five times as many crew hours to repair as non-device events.

After undergrounding, certain customers will completely avoid experiencing an interruption. This is modeled by assuming device events are reduced by the SUP percentage shown in Table 7-2, and non-device events are reduced by 90% of this percentage. The sum of these reductions results in a total work request reduction corresponding to the values in the "WR Reduction" column in Table 7-2.

After undergrounding, fewer damage locations will result in fewer crew hours required to repair storm damage. This is modeled by assuming the number of device events is reduced by the SUP percentage shown in Table 7-2, and non-device events are reduced by 90% of this percentage. The results in the expected percentages of crew hour reductions corresponding to the values in the "Crew-hr Reduction" column in Table 7-2.

8. Collective Customer Economic Benefits

When examining the financial impact of major weather events, it is well established that the impact to the local economy, and therefore the impact to the residents of this local economy, is the largest component. The most common methodology to quantify this impact is through an assessment of the impact of the major weather event on Gross Domestic Product (GDP). For example, GDP impact is the standard approach used by FEMA in making infrastructure investment decisions.

GDP is a measure of the size of an economy. It is equal to the value of all goods and services that are produced within the borders of an economy in a year. Since production is roughly equal to consumption in an economy, GDP can be used as a quantifiable measure of the economic well-being of people living within the borders of the GDP calculation.

One of the most disruptive events to a local economy is the widespread interruption of electricity service. When this happens, unrecoverable losses to local GDP occur, which results in less income and wealth for local residents. It is important to understand that this GDP effect is not based solely on the benefits to individual customers served from converted tap lines, but rather to all customers collectively across the affected service territory. These benefits are based on a shorter overall storm restoration since more crews that would otherwise be addressing damage on these tap lines can now be deployed elsewhere.

Some examples of how interruptions to electric service during major weather events reduced local GDP are:

- Telecommuters are not able to work from home, resulting in lost productivity and lost wages;
- Businesses are not able to open, resulting in lost productivity and lost wages;
- Household disruptions result in many having to forego work (such as parents having to stay home with children due to school closures), resulting in lost productivity and lost wages;

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- Public facilities that house emergency shelters are not able to perform their normal function, resulting in lost productivity;
- ATMs are not available, resulting in less local consumption; and
- Lost productivity and lost wages result in less local spending, creating a multiplier effect with regards to GDP impact.

According to the U.S. Department of Commerce, the GDP of Virginia in 2014 was \$463.613 billion, which is about \$50,000 per Virginia resident (2014 dollars). When performing an economic impact assessment related to Phase One, it is necessary to estimate the GDP associated with the parts of Virginia served by Dominion. To do this, it is assumed that GDP is proportional to energy usage. The Energy Information Administration (EIA) periodically compiles electricity statistics for each utility operating in each state. In 2013, Virginia had retail electricity sales of 110,511,827 MWh, with the Company accounting for 74,469,354 MWh, or 67% of the total. Therefore, it is assumed that the GDP associated with the Company's service territory in Virginia is 67% of the total Virginia GDP, or \$310.6 billion (Dominion Virginia Power Customer GDP).

Since this analysis examines the length of interruptions in hours, it is useful to calculate Dominion Virginia Power Customer GDP (GDP_{DVPC}) on a per hour basis. This corresponds to the following:

$$\text{GDP}_{\text{DVPC}} = \$310.613 \text{ B/yr} \div 8760 \text{ hr/yr} = \$35,457,991 \text{ per hour}$$

When calculating the GDP impact of a major weather event, it is necessary to determine the percentage of GDP reduction that occurs when compared to the total GDP activity that would have occurred had the major weather event not occurred. This is done by using a "GDP Factor" of 0.25.¹⁸ For example, a GDP Factor of 0.25 means that a 10-day storm will have a GDP

¹⁸ When the author performed a similar benefit-to-cost analysis for proposed hardening projects for the Public Utilities Commission of Texas, a GDP Factor of 0.33 was used. However, this assumption was based on coastal hurricane strikes to the Gulf Coast of Texas, which has concentrated economic centers. Therefore, the more conservative GDP Factor of 0.25 is used herein for the Phase One assessment.

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impact equivalent to $0.25 \times 10 \text{ days} = 2.5 \text{ days}$. Storm restoration duration is then assumed to be reduced according to the reduction in crew-hours required due to undergrounding. This results in the GDP benefits shown in Table 8-1.

Table 8-1. GDP Benefits of Phase One of Undergrounding

Storm	Duration (hrs)	Freq. (/yr)	% Customers	GDP Factor	GDP Impact	Crew-Hr Reduction	GDP Saved
A	20.0	11.71	1.57%	0.25	32,593,261	2.96%	963,157
B	32.8	4.72	3.19%	0.25	43,874,261	3.21%	1,406,468
C	58.7	1.63	6.96%	0.25	59,021,700	3.49%	2,058,692
D	78.1	0.96	10.24%	0.25	68,384,539	3.05%	2,086,340
E	120.5	0.44	18.68%	0.25	87,031,479	3.89%	3,386,036
F	182.0	0.20	34.13%	0.25	112,838,243	3.28%	3,698,575
G	337.0	0.066	89.85%	0.25	177,916,939	2.25%	4,004,631
Total GDP (\$/yr)					581,660,423		17,603,898

Crew efficiency in the early part of the storm is highest since they are primarily Company crews and contract crews regularly used by the Company. These crews are used to working every day on the Company's system, are familiar with Company processes, are familiar with Company construction standards, and are used to finding efficient routes to damage locations. Later in the storm, more crews from other regions of the country arrive and are less efficient.

Undergrounding will allow more work to be performed by efficient crews and therefore the total reduction in storm restoration duration should be higher than the percentage of crew-hour reduction. However, to be conservative, this analysis assumes that the total reduction in storm restoration duration is proportional to the reduction in crew hours.

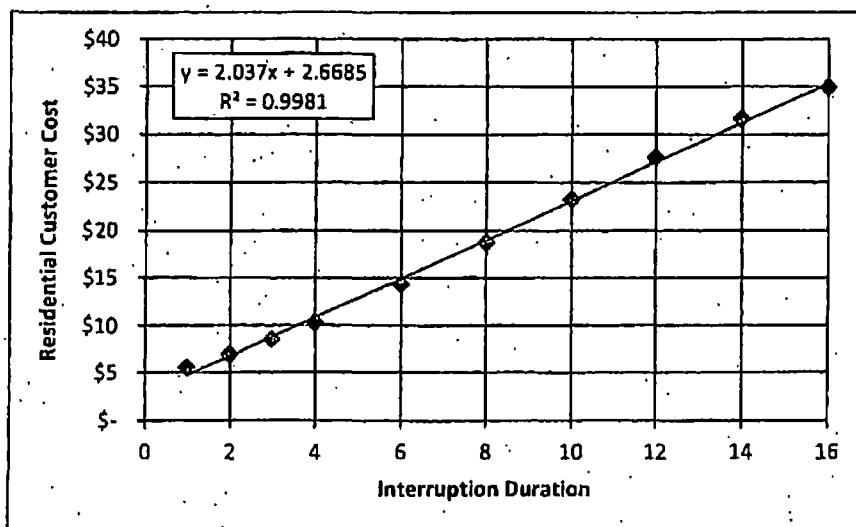
In summary, a conservative estimate of annual GDP savings from the implementation of Phase One that will result within the Company's service territory in Virginia is \$17,603,898.

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9. Individual-Level Customer Benefits

There is an amount of money that a customer would have been willing to pay to have avoided an interruption. This amount is referred to as the "customer cost" of the interruption and is separate from and in addition to the GDP impact discussed in the previous section. Customer costs will vary based on many factors such as customer-type, customer size, interruption length, time of day, day of week, season, and so forth. Averages are typically used that account for variations in the factors.

The U.S. Department of Energy has an online tool called the "Interruption Cost Estimate Calculator."¹⁹ The calculator allows the user to determine interruption costs for different customer types and for specific states. While the SUP provides overall reliability benefits to Dominion's Virginia customers, most of the customers impacted directly by SUP projects will be residential. The calculator was therefore used to determine the cost of residential customers in Virginia for interruptions of various durations. A summary of results is shown in Figure 9-1.²⁰



¹⁹ The calculator can be accessed at www.icecalculator.com

²⁰ These calculations are all for a single residential customer in Virginia, using default values for annual energy consumption and temporal distribution of interruptions (time-of-day and season).

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Figure 9-1. Residential Customer Cost versus Interruption Duration

As can be seen in Figure 9-1, the Interruption Cost Estimate Calculator uses a linear model for customer cost calculations. There is an initial cost of \$2.67 for a very short interruption, and an incremental cost of \$2.04 per hour. This model is consistent with my book on distribution reliability, which states, "Average customer cost curves tend to be linear and can be modeled as an initial cost plus a first-order time dependent cost."²¹

Using the restoration reduction models developed in Section 6, the expected number of avoided customer interruption hours can be calculated. This is done for each Storm A through G through the following formulae:

Customer Hours Interrupted = Duration x Freq. x Customers x Restoration Factor

Customer Hours Saved = Customer Hours Interrupted x Crew-Hr Reduction

Results for expected customer hours saved are shown in Table 9-1. The sum of all storms is equal to 503,164 hours of customer interruption hours that would have occurred but did not due to the undergrounding of tap lines.

Table 9-1. Customer Hours Saved for Phase One of Undergrounding Plan

Storm	Duration (hrs)	Freq. (/yr)	Customers		Restoration Factor	Cust-Hours Interrupted	Crew-Hr Reduction	Cust-Hours Saved
			%	#				
A	20.0	11.71	1.57%	37,229	9.72%	847,429	2.96%	25,042
B	32.8	4.72	3.19%	75,694	9.81%	1,151,278	3.21%	36,906
C	58.7	1.63	6.96%	165,155	9.99%	1,577,355	3.49%	55,019
D	78.1	0.96	10.24%	242,708	10.13%	1,852,442	3.05%	56,516
E	120.5	0.44	18.68%	442,938	10.42%	2,426,601	3.89%	94,409
F	182.0	0.20	34.13%	809,314	10.85%	3,276,075	3.28%	107,382
G	337.0	0.066	89.85%	2,130,493	11.94%	5,681,856	2.25%	127,890
Total customer hours of interruption (per year)						16,813,036		503,164

²¹ R.E. Brown, *Electric Power Distribution Reliability*, Second Edition, CRC Press, 2009, pp. 84.

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The individual customer monetary value of avoided interruption hours can be calculated by multiplying the hours saved by the cost-per-hour value of \$2.037. This calculation is conservative because it does not include the additional value experienced by customers that avoid interruptions entirely. The "interruption hours saved" value is therefore equal to the following:

$$\text{Interruption hours saved} = 503,164 \times \$2.037 = \$1,024,945 \text{ per year}$$

The Interruption Cost Estimate Calculator provides a valid estimate for the value of an avoided interruption hour, but its own website description states, "This tool is designed to estimate the costs of sustained interruptions lasting up to 16 hours. It is not meant to be applied to major outages or blackouts that last longer than 16 hours."

The difficulty in applying linear models like the Interruption Cost Estimate Calculator is due to hard-to-quantify factors including but not limited to: (1) spoiled food, which happens once during an extended outage and is therefore not able to be modeled as a linear function, and (2) hotel and restaurant expenses that some people will occur, but from which some local businesses will benefit.

To account for these costs associated with protracted interruptions, the following conservative assumptions are made. For food spoilage, it is assumed that each customer that avoids an interruption for Storms C through G (*i.e.*, restorations greater than 2.4 days) will avoid \$150 in food spoilage.²² For hotel and restaurant costs, it is assumed that 25% of customers avoiding an interruption during Storms C through G will avoid \$100 per day in expenses for half the duration of the restoration. For example, Storm F corresponds to an 8-day restoration. It is assumed that 25% of interrupted customers incur \$400 in hotel and restaurant costs.

²² A typical standard homeowner's policy does not cover food spoilage. The most common adder for food spoilage covers up to \$500 in food spoilage. This amount is subject to a deductible, and typically does not include spoilage due to electricity interruptions. However, the \$500 amount is a good basis for the conservative assumption of \$150 in average food spoilage, equal to 30% of the coverage amount.

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A summary of individual customer cost benefits due to reduced food spoilage and reduced hotel and restaurant costs is shown in Table 9-2. The column "CI Avoided" refers to the number of customer interruptions avoided during the storm. It is equal to the number of customers interrupted before undergrounding multiplied by the expected work request reduction due to 400 miles of undergrounding.

Table 9-2. Additional Customer Cost Savings for Phase One of Undergrounding

Storm	Freq. (/yr)	Customers	WR Reduction	CI Avoided	Food Spoilage		Hotels/Restaurants		
					Cost	Total	Cost	% Cust	Total
A	11.71	37,229	2.44%	10,625	0	0	0	0	0
B	4.72	75,694	2.64%	9,451	0	0	0	0	0
C	1.63	165,155	2.88%	7,731	150	1,159,642	100	25%	193,274
D	0.96	242,708	2.52%	5,895	150	884,323	150	25%	221,081
E	0.44	442,938	3.21%	6,196	150	929,365	250	25%	387,236
F	0.20	809,314	2.71%	4,499	150	674,799	400	25%	449,866
G	0.07	2,130,493	1.88%	2,661	150	399,222	700	25%	465,759
Total Customer Cost Avoided (\$/yr)					4,047,352		1,302,860		

In summary, Phase One of undergrounding corresponds to the individual-level residential customer cost savings shown in Table 9-3.

Table 9-3. Individual-Level Customer Cost Savings

Direct Residential Customer Cost Savings	\$/yr
Reduced Interruption hours	1,024,945
Reduced food spoilage	4,047,352
Reduced hotel/restaurant spending	1,302,860
Total	6,375,157

It should be noted at this point that there are other benefits to Phase One that are not represented in Table 9-1 as cost savings to Virginia customers. These additional items are discussed more fully in Section 10, but consist of items such as better reliability during normal weather conditions; enhancements to public safety; reduced human inconvenience and suffering; and eventual reduction in utility operations and maintenance expenses due to lower storm restoration costs and lower vegetation management costs.

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10. Benefit-to-Cost Assessment

This section performs a benefit-to-cost assessment (BCA) based on the benefit and cost calculations already performed in prior sections. All potential benefits are not considered. For example:

BCA does not consider the following potential aspects:

- Improved reliability during non-storm conditions;
- Direct and indirect economic activity generated by increased construction activity;
- Residual asset value after full depreciation;
- Economically-unquantifiable impacts related to safety, human inconvenience and suffering;
- Enhanced public safety; and
- Future reductions in utility operations and maintenance expenses due to lower storm restoration costs and lower vegetation management costs.

This BCA is performed based on Dominion's Phase One, which is 400 miles of overhead-to-underground conversion, with costs and benefits annualized over 39-years. Cost per mile of conversion is based on Company estimates.

The BCA is from a system-wide customer perspective, and therefore does not include the avoided cost of residents related to hotels and restaurants, since it is likely that most of these expenditures would remain within the local economy.

With these assumptions, the BCA is summarized in Table 10-1.²³

²³ These benefits and costs shown in Table 10-1 are averages that can be expected over time. For example, a mild weather year will result in significantly lower benefits for that year, and a severe weather year will result in significantly higher benefits for that year.

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Table 10-1. Benefit-to-Cost Assessment

Benefit-to-Cost Assessment (\$/yr)	
Costs	
Annualized cost of 400 miles	10,680,394
Benefits	
GDP loss avoidance	17,603,898
Reduced interruption hours	1,024,945
Reduced food spoilage	4,047,352
Total	22,676,195
Benefits / Costs	2.12

As expected, the majority of benefits from undergrounding during Phase One can be attributed to GDP loss avoidance. In fact, the costs of the program are fully justified by GDP loss avoidance alone, even when making conservative assumptions. This means that people living within the Dominion Virginia Power service territory are economically better off with Phase One than without, since the cost is less than the calculated economic activity benefit.

Significant additional direct customer benefits come from reduced interruption hours and reduced food spoilage. When adding these benefits to GDP loss avoidance, economic benefits are shown to be more than twice the associated costs. The additional benefits of reduced restaurant and hotel costs are not included since most of these expenditures would likely remain within the local economy.

In summary, a conservative assessment of cost and a conservative assessment of benefits show that the economic benefits of Dominion's Phase One of its overhead-to-underground conversion of tap lines are significantly higher than the costs of this conversion.

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11. Conclusions

In order to incur less damage during major storms and to therefore restore service to customers faster, the Company has initiated a Phase One of an overhead-to-underground conversion program called the Strategic Undergrounding Program (SUP). This program ranks overhead single-phase tap lines based on outage frequency, and targets the most outage prone for undergrounding.

This report has performed a benefit-to-cost assessment (BCA) for Phase One which would result in the undergrounding of 400 miles of tap lines, which is 2% of all tap lines and the minimum recommended for this type of program. The Company expects that it can accomplish this in the three years ending August 31, 2016. The estimated cost of undergrounding during Phase One is \$350,000 per mile, for a total cost of \$140,000,000. This amount corresponds to an annualized cost of \$10,680,394 per year over thirty-nine years. It is appropriate to compare this annualized cost to annual customer benefits for the purposes of a benefit-to-cost assessment.

A detailed storm and storm restoration model has been developed based on historical outage records of the Company's major weather events. This model is able to estimate the frequency of storms of various magnitudes, their restoration time, the number of customers affected, the number of customer interruption hours, and the number and types of damage locations. Using this model, the benefits of underground conversion are quantified in terms of collective customer economic benefits and individual-level customer economic benefits.

Collective customer economic benefits are defined as increased GDP in the Dominion Virginia Power service territory due to shorter storm restoration duration. These are calculated to be an average of \$17,603,898 per year.

Individual-level customer economic benefits include the value of reduced customer interruption hours, reduced food spoilage, and reduced hotel/restaurant spending. These benefits are:

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Table 11-1. Individual-Level Cost Savings

Individual Level Residential Customer Cost Savings	\$/yr
Reduced interruption hours	1,024,945
Reduced food spoilage	4,047,352
Reduced hotel/restaurant spending	1,302,860
Total	6,375,157

A benefit-to-cost analysis (BCA) has been performed based on Phase One consisting of 400 miles of overhead-to-underground conversion, with costs and benefits annualized over 39-years. The BCA is from a local economic perspective, and therefore does not include the avoided cost of residents related to hotels and restaurants since it is likely that most of these expenditures would remain within the local economy. With these assumptions, the BCA is:

Table 11-2. Benefit-to-Cost Assessment

Benefit-to-Cost Assessment (\$/yr)	
Costs	
Annualized cost of 400 miles	10,680,394
Benefits	
GDP loss avoidance	17,603,898
Reduced interruption hours	1,024,945
Reduced food spoilage	4,047,352
Total	22,676,195
Benefits / Costs	2.12

As can be seen, a conservative assessment of cost and a conservative assessment of benefits show that the economic benefits of the overhead-to-underground conversion of 400 miles of underground tap lines laterals in Phase One are significantly higher than the costs of this conversion. The actual value to customers will be higher due to both conservative assumptions and non-monetized benefits.

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Some of the conservative assumptions used in the BCA are:

- No residual value of installed facilities after 39 years;
- IEEE calendar day effect reduces actual major weather event duration and customer impact;
- Benefits of customers completely avoiding an interruption are not included;
- No customer growth is assumed;
- No GDP growth is modeled; and
- Storm restoration duration reductions are probably more due to the increased use of efficient crews.

Some of the benefits not quantified in the BCA for purposes of this analysis are:

- Improved reliability during non-storm conditions;
- Direct and indirect economic activity generated by increased construction activity;
- Economically-unquantifiable impacts related to public safety, human inconvenience and suffering;
- Enhanced public safety; and
- Eventual lower utility operations and maintenance expenses due to lower storm restoration costs and lower vegetation management costs.

In summary, a conservative analysis shows that the Company's program of converting 400 miles of tap lines from overhead to underground has a Virginia customer benefit-to-cost ratio of more-than two to one.

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Appendix A – CV of Richard E. Brown

Richard Brown is an internationally recognized industry expert in electric system infrastructure, electric system operations, system planning, asset management, and economic analysis. He has submitted expert witness testimony to regulatory commissions in the states of California, Florida, Maryland, Massachusetts, and Texas. He has published more than 90 technical papers, has taught courses in eleven countries, and is author of the books *Electric Power Distribution Reliability* and *Business Essentials for Utility Engineers*. Dr. Brown is an IEEE Fellow and a registered professional engineer.

Professional Experience

Title	Institution	Dates
Practice Director and Principal Engineer	Exponent	3/2014 - present
Vice President, USAC Power Networks	WorleyParsons	3/2012 - 2/2014
Vice President, Operations	Quanta Technology	7/2006 - 2/2012
Vice President, Asset Management	KEMA	5/2003 - 6/2006
Director of Technology	ABB Consulting	5/2001 - 4/2003
Principal Engineer	ABB Power Distribution Solutions	2/1999 - 4/2001
Senior Engineer	ABB Corporate Research	7/1996 - 1/1999
Research/Teaching Assistant	University of Washington	1/1994 - 6/1996
Electrical Engineer II-III	Jacobs Engineering	4/1991 - 12/1993

Dr. Brown has been an adjunct faculty member of North Carolina State University since 2008.

Education

Degree	Institution	Location	Year Received
M.B.A.	University of North Carolina (Kenan-Flagler)	Chapel Hill, NC	2003
Ph.D.	University of Washington	Seattle, WA	1996
M.S.E.E.	University of Washington	Seattle, WA	1993
B.S.E.E.	University of Washington	Seattle, WA	1991

Honors and Awards

- IEEE Technical Committee Working Group Recognition Awards: Electric Delivery System Reliability Tutorial Working Group (2007); Aging Power System Infrastructure (2007); T&D Asset Management (2006); Transmission Planning (2008)
- IEEE PES Walter Fee Outstanding Young Engineer Award (2003)
- ABB Award of Excellence: President's Award (1999)
- ABB Award of Excellence: Product Development (1998)
- Member, Eta Kappa Nu (Electrical Engineering Honor Society)
- Member, Beta Gamma Sigma (Business Honor Society)

Professional Registration and Professional Societies

- IEEE Fellow
- Registered Professional Engineer in the State of North Carolina (Certificate No. 23088)

IEEE Power Engineering Society Activities

- Elected IEEE Fellow in 2007 for "contributions to distribution system reliability and risk assessment." The grade of Fellow is conferred by the IEEE Board of Directors for an extraordinary record of industry accomplishments, and is limited to one-tenth of one percent of the total voting membership per year.
- Awards
 - Technical Committee Working Group Recognition Award (2008). Awarded by the Power System Operations Committee for work on power system transmission planning.

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- Technical Committee Working Group Recognition Award (2007). *Awarded by the Power System Analysis, Computing & Economics Committee for contributing to the development of an electric delivery system reliability tutorial.*
- Technical Committee Working Group Recognition Award (2007). *Awarded by the Power System Operations Committee for work on Aging Power System Infrastructure.*
- Technical Committee Working Group Recognition Award (2006). *For work which resulted in a special issue of the IEEE Power and Energy magazine, May 2005.*
- Walter Fee Outstanding Young Engineer Award (2003). *For outstanding contributions in predictive reliability modelling of distribution systems.*
 - Chair, Technical Awards Committee (2007.- present)
 - Member, Power System Planning and Implementation Committee (1997-present)
- Committee Vice Chair (2006-2008)
- Chair, Distribution Working Group (2003-2006)
- Chair, Power Delivery Reliability Working Group (1997-1999)
 - Member, Distribution Subcommittee, Working Group on System Design (1997-present)
 - Technical Paper Reviewer
- *IEEE Transactions on Power Systems* (1996-present)
- *IEEE Transactions on Power Delivery* (1996-present)
- *IEEE General Meeting* (2001-present)
- *IEEE T&D Conference and Exposition* (2001-present)
- *IEEE Power Systems Conference and Exposition* (2004-present)
- Power Systems Computation Conference 2008
 - President, University of Washington Student Chapter (1994-1995)
 - Vice President, University of Washington Student Chapter (1993-1994)

Books, Book Chapters, and Theses

1. R. E. Brown, *Business Essentials for Utility Engineers*, CRC Press, 2010.
2. R. E. Brown, *Electric Power Distribution Reliability, Second Edition*, CRC Press, 2009.
3. R. E. Brown, *Electric Power Distribution Reliability*, Marcel Dekker, 2002.
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9. R. E. Brown, *Reliability Assessment and Design Optimization for Electric Power Distribution Systems*, Ph.D. Dissertation, University of Washington, Seattle, WA, 1996.
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2. R. E. Brown, G. Frimpong, and H. L. Willis, "Failure Rate Modeling Using Equipment Inspection Data", *IEEE Transactions on Power Systems*, Vol. 19, No. 2, May 2004, pp. 782-787.
3. S. S. Venkata, A. Pahwa, R. E. Brown, and R. D. Christie, "What Future Distribution Engineers Need to Learn," *IEEE Transactions on Power Systems*, Vol. 19, No. 1, Feb. 2004, pp. 17-23.
4. F. Li and R. E. Brown, "A Cost-Effective Approach of Prioritizing Distribution Maintenance Based on System Reliability," *IEEE Transactions on Power Delivery*, Vol. 19, No. 1, Jan. 2004, pp. 439-441.

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11. R. E. Brown, T. M. Taylor, "Modeling the Impact of Substations on Distribution Reliability," *IEEE Transactions on Power Systems*, Vol. 14, No. 1, Feb. 1999, pp. 349-354.
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16. V. N. Chuvychin, N. S. Gurov, S. S. Venkata, and R. E. Brown, "An Adaptive Approach to Load Shedding and Spinning Reserve Control During Underfrequency Conditions," *IEEE Transactions on Power Systems*, Vol. 11, No. 4, Nov. 1996, pp. 1805-1810.

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2. J. Romero Agüero, R. E. Brown, J. H. Spare, E. Phillips, L. Xu, and J. Wang, "A Reliability Improvement Roadmap Based on a Predictive Model and Extrapolation Technique," *IEEE PES 2009 Power Systems Conference and Exposition*, Seattle, WA, March 2009.
3. J. Romero Agüero, R. E. Brown, J. H. Spare, E. Phillips, L. Xu, and J. Wang, "A Reliability Improvement Roadmap Based on a Predictive Model and Extrapolation Technique," *DistribUTECH Conference and Exhibition*, San Diego, CA, Feb. 2008.
4. R. E. Brown, "Asset Management Standards and Guidelines," *EPRI Fourth Power Delivery Asset Management Conference*, Chicago, IL, Oct. 2008.
5. R. E. Brown, "Impact of Smart Grid on Distribution System Design," *IEEE PES 2008 General Meeting*, Pittsburg, PA, July 2008.
6. L. Xu and R. E. Brown, "A Hurricane Simulation Method for Florida Utility Damage and Risk Assessment," *IEEE PES 2008 General Meeting*, Pittsburg, PA, July 2008.
7. R. E. Brown, "Hurricane Hardening Efforts in Florida," *IEEE PES 2008 General Meeting*, Pittsburg, PA, July 2008.
8. L. Xu and R. E. Brown, "Simulation of Hurricane Damage to Utilities in Florida," *DistribUTECH Conference and Exhibition*, Tampa Bay, FL, Jan. 2008.
9. R. E. Brown, "Reliability Benefits of Distributed Generation on Heavily Loaded Feeders," *IEEE PES 2007 General Meeting*, Tampa, FL, June 2007.
10. R. E. Brown, "Pole Hardening Following Hurricane Wilma," 2007 Southeastern Utility Pole Conference, Tunica, MS, Feb. 2007.

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14. R. E. Brown, "Project Selection with Multiple Performance Objectives," 2005 IEEE/PES Transmission and Distribution Conference and Exposition, New Orleans, LA, Sept. 2005.
15. R. E. Brown and J. H. Spare, "The Effects of System Design on Reliability and Risk," 2005 IEEE/PES Transmission and Distribution Conference and Exposition, New Orleans, LA, Sept. 2005.
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21. H. L. Willis, M. V. Engel and R. E. Brown, "Equipment Demographics - Failure Analysis of Aging T&D Infrastructures," 2004 Canada Power Conference, Toronto, Canada, September 2004.
22. R. E. Brown, "Failure Rate Modeling Using Equipment Inspection Data," *IEEE PES 2004 General Meeting*, Denver, CO, June 2004.
23. R. E. Brown, "Conting to Grips with Distribution Asset Management," 2003 Real World Conference: It's All About Cost and Reliability, Transmission and Distribution World, Ft. Lauderdale, FL, Oct. 2003.
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30. R. E. Brown, "Web-Based Distribution System Planning," *IEEE PES Summer Power Meeting*, Chicago, IL, July 2002.
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1. R. E. Brown, "Storm Hardening Distribution Systems," *Transmission and Distribution World*, June 2010, pp. 50-56.
2. H. L. Willis and R. E. Brown, "What Happens with a Lack of Long Range T&D Infrastructure Planning?" *Natural Gas & Electricity*, Vol. 24, Issue 6, Jan. 2008, pp. 22-27.
3. R. E. Brown, "Increased Performance Expectations for Major Storms," *Electric Perspectives*, EEL (to be published in 2007)
4. M. V. Engel, R. E. Brown, E. Phillips, and N. Bingel, "Extreme Winds Test Wood Pole Strength," *Transmission and Distribution World*, May 2007, pp. 34-38.
5. D. J. Morrow and R. E. Brown, "Future Vision," *IEEE Power and Energy Magazine*, Vol. 5, Issue 5, Sept./Oct. 2007, pp. 36-45.

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6. R. E. Brown and H. L. Willis, "The Economics of Aging Infrastructure," *IEEE Power and Energy Magazine*, Vol. 4, No. 3, May/June 2006, pp. 36-43.
7. R. E. Brown and B. G. Humphrey, "Asset Management for Transmission and Distribution," *IEEE Power and Energy Magazine*, Vol. 3, No. 3, May/June 2005, pp. 39-45.
8. R. E. Brown, "Asset Management: Balancing Performance, Cost, and Risk," *EnergyPulse Special Issue on Asset Management*, www.energycentral.com, Feb. 2005.
9. P. Musser, R. E. Brown, T. Eyford, and C. Warren, "Too Many Routes of Reliability," *Transmission and Distribution World*, June 2004, pp. 17-22.
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11. R. E. Brown and L. A. A. Freeman, "A Cost/Benefit Comparison of Reliability Improvement Strategies," *Electric Power and Light*, May 2003.
12. R. E. Brown, H. Kazemzadeh, B. R. Williams and C. B. Mansfield, "Engineering Tools Move into Cyberspace," *Transmission and Distribution World*, March 2003, pp. 27-36.
13. F. Li, L. A. A. Freeman and R. E. Brown, "Web-Enabling Applications for Outsourced Computing," *IEEE Power and Energy Magazine*, Vol. 1, No. 1, January/February 2003, pp. 53-57.
14. P. Perani and R. E. Brown, "Maintaining Reliable Power For Semiconductor Manufacture," *What's New in Electronics*, March 2002.
15. P. Perani and R. E. Brown, "Rock Steady: The Importance of Reliable Power Distribution in Microprocessor Manufacturing Plants," *ABB Review*, No. 3, 2002, pp. 29-33.
16. H. L. Willis and R. E. Brown, "Is DG Ready for the Last Mile?" *Power Quality (cover story)*, March 2002, pp. 16-21.
17. R. E. Brown and M. W. Marshall, "The Cost of Reliability," *Transmission and Distribution World (cover story)*, Dec. 2001, pp. 13-20.
18. R. E. Brown, P. R. Jones and S. Trotter, "Planning for Reliability," *Trans-Power Europe*, Vol. 1, No. 1, March 2001, pp. 10-12.
19. R. E. Brown, A. P. Hanson, H. L. Willis, F. A. Luedtke, M. F. Born, "Assessing the Reliability of Distribution Systems," *IEEE Computer Applications in Power*, Vol. 14, No. 1, Jan. 2001, pp. 44-49.
20. R. E. Brown and B. Howe, "Optimal Deployment of Reliability Investments," *E-Source, Power Quality Series: PQ-6*, March 2000.

Regulatory Experience

Dr. Brown has filed the following expert testimony before public utility commissions (copies are available upon request):

1. Prepared direct testimony, reply testimony, and surreply testimony, "Investigation of the reliability of Pepco's electric distribution system and the quality of the service it provides to customers," Prepared on behalf of the Massachusetts Attorney General Filed and submitted to the Maryland Public Service Commission under Case No. 9240. *This testimony performs a review of the following reports generated to assess the reliability of Pepco's reliability and customer service during both normal and major event conditions:* "
2. "Impact of Aging Infrastructure on System Reliability at SCE," Workpaper submitted with the 2012 General Rate Case to Public Utilities Commission of the State of California, Docket U 338-E, 2010. *This report examines the impact of aging equipment on system reliability over twenty years, and calculates the benefit-to-cost ratios of proactive aging infrastructure replacement for both the overall system and for worst-performing circuits.*
3. "Hazard Trees: Benchmark Survey and Best Practices." Prepared for the Public Utilities Commission of Texas and filed under docket number 36375. The results of this report were presented to the commission in an open meeting on July 30th 2009. *A industry benchmark survey was performed to determine typical and best industry practices related to the identification and removal of trees with defects that have the potential to fall into power lines. The report identifies eighteen recommendations.*
4. "Distribution Hardening: Benchmark Survey and Best Practices." Prepared for the Public Utilities Commission of Texas and filed under docket number 36375. The results of this report were presented to the commission in an open meeting on July 30th 2009. *A industry benchmark survey was performed to determine typical and best*

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- industry practices related to hardening distribution systems so that they experience less damage during major storms. The report identifies eighteen recommendations*
5. Prepared direct, rebuttal, and surrebuttal testimony, "Investigation by the Massachusetts Department Of Public Utilities on its Own Motion into the Preparation and Response of the Massachusetts Electric Distribution Companies to the December 12, 2008 Winter Storm," Prepared on behalf of the Massachusetts Attorney General Filed and submitted to the Massachusetts Department Of Public Utilities under Docket DPU 09-01-A. *This testimony presents an analysis of the technical aspects of Fitchburg Gas & Electric (FG&E) as they relate to the damage and restoration associated with the 2008 Ice Storm.*
 6. "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs." Prepared for the Public Utilities Commission of Texas and filed under docket number 36375. The results of this report were presented to the commission in an open meeting on April 9th 2009. *This report examines the impact of hurricanes and tropical storms to electric and telecom utilities in Texas. It examines the cost-effectiveness of potential hardening programs such as vegetation patrols, hazard tree programs, ground-based inspections, locating substations outside of floodplains, emergency backup generation in central offices, underground conversion, smart grid technologies, targeted hardening, and post-storm data collection. This report determines the costs for each program, the direct utility benefits, and greater societal benefits*
 7. "Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion." Prepared for the Florida Electric Utilities and submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI. The results of this report were presented to the commission in an internal affairs meeting. *This report describes the body of literature related to the costs and benefits of converting existing overhead distribution systems to underground, including the impact on non-storm reliability performance and storm reliability performance. Phase 2 of this project will examine for case studies for actual underground conversion projects that have been completed in Florida. Phase 3 of this project will develop a model that is able to predict the anticipated costs and benefits for potential underground conversion projects.*
 8. "Undergrounding Assessment Phase 2 Final Report: Undergrounding Case Studies." Prepared for the Florida Electric Utilities and submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI. The results of this report were presented to the commission in an internal affairs meeting. *This report details four actual undergrounding projects that have been completed in Florida with respect to realized benefits and incurred costs.*
 9. "Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modelling." Prepared for the Florida Electric Utilities and submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI. The results of this report were presented to the commission in an internal affairs meeting. *This report develops a methodology to assess the utility and customer costs and benefits of undergrounding and system hardening with an emphasis on hurricane performance. It also contains a user's guide to the software tool in which the methodology is implemented.*
 10. "Technical Report: Post Hurricane Wilma Engineering Analysis." Prepared for Florida Power & Light and submitted to the Florida Public Service Commission for the 2005 hurricane cost recovery hearings, Docket 060038-EI. A deposition was given on the findings of this report and Dr. Brown was called as an expert witness in the FPL storm cost recovery hearings. *This report examines the infrastructure damage that occurred on the FPL system following Hurricane Wilma, and determines whether this damage was consistent with prudent management decisions and therefore eligible for recovery of the associated recovery costs.*
 11. "Hurricane Hardening." January 23rd 2006 (undocketed). Transcript available on the FPSC website. *Presented techniques at a staff workshop for strengthening electric power systems so that they sustain less damage during hurricane.*
 12. "Assessment of PBR Reliability Metrics and Related Systems and Processes." Prepared for Southern California Edison and submitted to the California Public Utilities Commission under Docket I.06-06-014. *This testimony examined the systems and processes of SCE related to reliability data gathering and reliability index calculations used for PBR metrics during the PBR period of 1997 through 2003. The focus of the testimony was on the ability of the SCE systems and processes to generate reliability metrics that are useful from a regulatory incentive perspective.*
 13. "Asset Management and System Reliability Group Review," Prepared for Southern California Edison and submitted to the California Public Service Commission for the 2008 general rate case, Docket A.07-11-011. *This report examines, among other things, the impact that aging infrastructure will have on distribution reliability indices over time, and the mitigation impact of the proactive replacement activities proposed in the rate case.*

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14. "A Better Measure for Distribution Reliability," Prepared for San Diego Gas & Electric and submitted to the California Public Service Commission for the 2007 general rate case, Docket A:06-12-009. *This report discusses the strengths and weaknesses of standard reliability indices when used for prioritizing reliability improvement projects. The report discusses potential difficulties associated with the most common indices (SAIDI, SAIFI, and MAIFI), examines alternatives, and proposes a new reliability index that is highly suitable for performance-based ratemaking.*
15. "Aging Distribution Infrastructure at Pacific Gas & Electric." Prepared for Pacific Gas & Electric and submitted to the California Public Service Commission for the 2006 general rate case, Docket A-05.12-002. *This report examines the state of the U.S. electric industry in terms of aging infrastructure and its impact on reliability performance. It then compares these findings to the situation at PG&E, and examines the appropriateness of related spending proposed in the general rate case with regards to cost and reliability benefits.*

Dr. Brown has also supported several utilities in regulatory activities that did not result in filed testimony. These include:

16. Excel Energy – Assessment of Reliability Reporting Systems and Processes. *This project was a result of accusation that Excel Energy was manipulating reliability indices for the purposes of avoiding regulatory financial penalties. The scope of the project included a comprehensive assessment of systems and processes and their ability to generate reliability indices that are useful for their intended regulatory purpose. This included an industry benchmark study.*
17. Oklahoma Gas & Electric – Five-year reliability plan for rate case filing. *This engagement created a cost-versus reliability curve for the OG&E system. This curve to set five-year reliability improvement and spending targets for inclusion in their 2006 rate case filing.*

Dr. Brown has also served as an expert witness in the following civil cases:

18. Jersey Central Power & Light. Provided expert witness services for a pole collision case (Seals, et al. v. JCP&L, et al.) including two reports, two depositions, and trial testimony. This case involved a driver colliding with a pole and asserting that the utility was to blame for the accident. The jury verdict assigned 100% blame to the plaintiff and 0% blame to the utility.

Developed Courses

Dr. Brown has designed the curriculum, developed the material, and taught the following courses:

1. Distribution Reliability, 4-day course.
2. Power System Reliability, 4-day course.
3. Asset Management, 4-day course.
4. Business Essentials for Utility Engineers, 4-day course.
5. Utility Infrastructure Hardening, 2-day course.